Application No.:	A.15-04-013
Exhibit No.:	SCE-
Witnesses:	Gary Holdsworth Dana Cabbell Phil Hung Kathy Hidalgo

SOUTHERN CALIFORNIA EDISON®

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(U 338-E)

Southern California Edison Company's (U 338-E) Direct Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

PUBLIC VERSION

Before the

Public Utilities Commission of the State of California

Rosemead,
California
March 1, 2019

SCE's Direct Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project

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I.

Introductory Statement

On April 15, 2015, Southern California Edison Company (SCE) filed Application No. 15-04-013 (subsequently amended on April 30, 2015) with the California Public Utilities Commission ("Commission" or "CPUC") for a Certificate of Public Convenience and Necessity ("CPCN") to permit SCE to construct its portion of the Riverside Transmission Reliability Project ("RTRP" or "Project"). The RTRP includes components that would be owned and operated by City of Riverside's Municipal Utility Department, Riverside Public Utilities (the City of Riverside and Riverside Public Utilities are collectively referred to herein as "Riverside") and SCE in their individual capacities. Specifically, Riverside intends to construct, own, operate, and maintain certain elements of the RTRP, including the new 230/69 kilovolt (kV) Wilderness Substation, 69 kV subtransmission lines, and interconnection and telecommunication facilities. In contrast, the CPCN Application at issue here is filed in support of SCE's construction, operation, and maintenance of other elements of RTRP, including:

- approximately 8 miles of new overhead 230 kV[1] transmission line;
- approximately 2 miles of new underground 230 kV transmission line;
- new 230 kV Wildlife Substation;
- modifications of existing overhead distribution lines;
- modifications at existing substations; and
- telecommunication facilities between the existing Mira Loma and Vista Substations, and the proposed Wildlife Substation.

Riverside approved the RTRP supported by an Environmental Impact Report ("EIR") prepared pursuant to the California Environmental Quality Act (Cal. Pub. Resources Code §§ 21000, *et seq.*, "CEQA") and adopted on or about February 5, 2013. Riverside's approval of the RTRP was then

[1] RTRP's proposed facilities may be referenced by their nameplate or nominal capacity ratings, *i.e.*, 230 kV and 69 kV transmission facilities, or by their functional voltage, *i.e.*, 220 kV and 66 kV transmission facilities.

challenged in California Superior Court and the Court of Appeals by the City of Jurupa Valley ("Jurupa Valley"), which alleged RTRP's approval violated CEQA. Riverside's 2013 EIR was upheld by both the California Superior and Appellate Courts, which dismissed Jurupa Valley's legal challenges. On April 23, 2014, Jurupa Valley's subsequent petition for writ of review by the Supreme Court of California was denied.

Nevertheless, following the 2013 certification of the RTRP EIR, certain residential developments within SCE's proposed transmission line route were approved and entitled by Jurupa Valley. By the time the CPUC's Energy Division deemed the RTRP CPCN Application complete on January 5, 2017, construction of certain housing developments had begun with some residences already complete and available for sale. Construction of the originally proposed RTRP transmission line route would now require SCE to acquire property rights and/or claim eminent domain through these newly constructed housing developments, including the Lennar Homes' Riverbend Community ("Riverbend") and the Vernola Marketplace Apartment Community ("Vernola Apartments").

On or about August 17, 2016, SCE filed its Supplemental Response to Question 3 of the May 22, 2015 Deficiency Report for RTRP with the CPUC wherein, pursuant to discussions and subsequent agreements between SCE, Riverside, and the owners of the Riverbend and Vernola Apartment Projects, SCE proposed to pursue, as its preferred Project route, a "hybrid" aboveground / underground alternative 230 kV transmission line route (the "Hybrid Route") in the pending RTRP CPCN proceeding. The Hybrid Route proposes underground construction of the 230 kV transmission lines within public rights-of-way immediately adjacent to the Riverbend and Vernola Apartment Projects and avoids directly impacting them, but maintained overhead construction for the remaining portions of the route.

The CPUC's Energy Division determined that changes in the baseline physical condition (specifically, the entitlement and development of the Riverbend and Vernola Apartment Projects) and changes in the project description (the undergrounding associated with SCE's proposed Hybrid Route to avoid impacting those housing projects) required additional analysis under CEQA. On or about January 25, 2017, the CPUC's Energy Division issued a Notice of Preparation of a Subsequent EIR ("SEIR") which proposed to address those aspects of the Proposed Project (now the Hybrid Route) that were not previously analyzed by Riverside in its 2013 EIR.

On or about April 2, 2018 the Energy Division published the Draft SEIR, accepting comments through May 17, 2018. The Final SEIR was released on or about October 2, 2018.

On November 13, 2018, Administrative Law Judge Hallie Yacknin presided over a prehearing conference ("PHC") supporting RTRP in San Francisco, California to resolve preliminary matters. On December 20, 2018, Commissioner Liane M. Randolph issued an Assigned Commissioner's Scoping Memo and Ruling ("Scoping Memo") establishing the issues to be determined in the CPUC's review of the RTRP. The Scoping Memo (at pp. 2-4) identifies contested issues of material fact requiring an evidentiary showing as: the bases for the infeasibility of any mitigation measures or Project alternatives, whether there are overriding considerations of RTRP that may outweigh the unavoidable adverse environmental impacts identified in the Final SEIR, whether RTRP serves a present or future public convenience and necessity, and the maximum prudent and reasonable cost of RTRP. Further, while the Scoping Memo states (at p. 9) that EMF policy compliance "does not implicate any contested material fact requiring evidence," for the purpose of completing the administrative record in this proceeding, SCE provides testimony herein regarding EMF policy compliance with respect to the Hybrid Route alternative, as well as the other alternatives considered in the SEIR.

In accordance with the Scoping Memo, SCE hereby serves the following direct testimony regarding:

1. SCE's consideration of, and decision to enter into, an Interconnection Facilities Agreement and provide expanded service to Riverside, consistent with SCE's obligation to serve its customers (including municipal utilities interconnected with SCE's electrical grid) in a non-discriminatory manner pursuant to its tariffs, sponsored by Gary Holdsworth;[2]

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[2] Scoping Memo Issues 6 ("*To the extent that the proposed project and/or project alternatives results in significant and unavoidable impacts, are there overriding considerations that nevertheless merit Commission approval of the proposed project or project alternative?*") and 7 ("*Does the proposed project serve a present or future public convenience and necessity? This issue directly overlaps issue 6, above.*").

2. How RTRP was designed and proposed to serve the public convenience and necessity in a manner consistent with prudent electric system planning and engineering principles, sponsored by Dana Cabbell;[3]
3. The maximum prudent and reasonable cost of RTRP and the estimated cost of the Project alternatives (which SCE plans to argue renders them infeasible as a matter of public policy), sponsored by Kathy Hidalgo;[4] and
4. RTRP's compliance with the Commission's policies governing the mitigation of EMF effects using low-cost and no-cost measures, sponsored by Phil Hung.[5]

SCE expects that Riverside will serve direct testimony under separate cover regarding the issues identified in Scoping Memo Issue 7, including:

1. A general description of the city of Riverside's electric system and interconnection with SCE at Vista Substation and the need for the RTRP;
2. Riverside's actual peak demand growth in the past ten years;
3. The inadequacy of the existing interconnection between SCE and Riverside to serve Riverside's existing and anticipated load growth and why a second point of interconnection between SCE and Riverside is needed to reduce the dependence on the current single interconnection point and ensure reliability; and
4. Why RTRP is needed to ensure reliability of service to Riverside.[6]

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[3] *Id.*

[4] Scoping Memo Issues ## 5 ("*Are the mitigation measures or project alternatives infeasible? This issue encompasses consideration of community values pursuant to Pub. Util. Code § 1002(a)(1)*") and 8 ("*What is the maximum prudent and reasonable cost of the project? (See Pub. Util. Code § 1005.5.)*").

[5] Scoping Memo Issue # 9 ("*Does the project design comply with the Commission's policies governing the mitigation of EMF effects using low-cost and no-cost measures?*").

[6] Scoping Memo Issues ## 6 ("*To the extent that the proposed project and/or project alternatives results in significant and unavoidable impacts, are there overriding considerations that nevertheless merit Commission approval of the proposed project or project alternative?*") and 7 ("*Does the proposed project serve a present or future public convenience and necessity? This issue directly overlaps issue 6, above*.").

II.

SCE's Direct Testimony Regarding Its Obligations To Serve Its Customers Such As Riverside In A Non-Discriminatory Manner Pursuant To Its Tariffs And The Qualifications Of Gary Holdsworth [7]

Q: ***Please state your name and business address for the record.***

A: My name is Gary Holdsworth, and my business address is 3 Innovation Way, Pomona, California, 91768.

Q: ***Briefly describe your education, work history and present responsibilities at SCE.***

A: I received my Bachelor of Science in Business from Brigham Young University, followed by a Masters Degree in Business Administration in Corporate Finance from the University of Southern California. My career at SCE started in 2004 and has included Project Management roles in Transmission and Distribution ("T&D") Business Planning and Transmission Regulatory Policy, where I was responsible for interconnection policy development and advocacy on behalf of SCE during several rounds of interconnection process reform. In 2011, I accepted my current position as a Senior Manager in the Grid Interconnection and Contract Development group ("GICD"). GICD is responsible for managing the interconnection process for generating facilities and wholesale loads throughout SCE's service territory. Although my department has reorganized and changed names several times, I have held essentially the same position and had essentially the same responsibilities since 2011.

Q: ***Please describe your role with respect to the RTRP.***

A: As Senior Manager of the GICD group, I am responsible for administering the end-to-end interconnection process for generating and energy storage resources as well as wholesale load increase requests, such as SCE received from Riverside. In this role I am responsible for maintaining strong

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[7] This section addresses Scoping Memo Issues ## 6 ("*To the extent that the proposed project and/or project alternatives results in significant and unavoidable impacts, are there overriding considerations that nevertheless merit Commission approval of the proposed project or project alternative?*") and 7 ("*Does the proposed project serve a present or future public convenience and necessity? This issue directly overlaps issue 6, above*.").

customer relationships with our interconnection customers. I manage a team of interconnection agreement negotiators that work closely with interconnection and load customers throughout the multi-year interconnection process. In this role, since 2011, I have also overseen negotiations between SCE and Riverside regarding the required amendments to the Interconnection Facilities Agreement ("IFA") related to the RTRP.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony in this proceeding is to sponsor portions of *Southern California Edison Company's (U 338-E) Direct Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project* related to SCE's tariffs under which Riverside is interconnected to the SCE electrical grid and how this interconnection serves and furthers the public convenience and necessity.

A. <u>Genesis of SCE's Role Supporting RTRP</u>

Q: Please explain how GICD first became involved with what would ultimately become RTRP.

A: GICD's involvement arises out of SCE's obligation to provide all customers with reliable service. Once SCE becomes aware that a wholesale interconnection customer (like Riverside) might need expanded or additional service that could include a new interconnection point, my GICD group would: oversee the consideration of that potential need; coordinate with SCE's Integrated System Planning organization (further discussed by Dana Cabbell below); negotiate relevant agreements (or amendments of existing agreements); and manage the process for implementing any required facilities to enable that new or expanded service. That is what happened here.

B. <u>SCE's Obligation to Serve Interconnection Requests Under Current Tariffs</u>

Q: What is the WDAT and what does SCE believe it requires with respect to municipal utility customers such as Riverside?

A: The Wholesale Distribution Access Tariff ("WDAT") is SCE's operational tariff that establishes obligations and procedures applicable to SCE's provision of service to wholesale power customers. Riverside has taken wholesale electric service at 69 kV from SCE since the 1960s under the WDAT so that Riverside can then provide retail power to its customers. By its terms, SCE's WDAT provides, in relevant part, that the

> Distribution Provider [SCE] will provide Distribution Service pursuant to the applicable terms and conditions contained in this Tariff and Service Agreement. … for the transportation of capacity and energy that is (1) generated or purchased by a Distribution Customer [*e.g.*, Riverside here] at a generation source and transported to the ISO Grid using the Distribution Provider's Distribution System, or (2) generated or purchased by a Distribution Customer from generation sources and transported from the ISO Grid to the Distribution Customer's Service Area using the Distribution Provider's Distribution System. … Distribution Service shall be provided between the Distribution Provider's interconnection with the ISO Grid and the Distribution Customer's interconnection with the Distribution Provider's Distribution System. The Distribution Customer shall obtain and pay for Transmission Service from the ISO for such energy and capacity delivered to the ISO Grid or for energy and capacity received from the ISO Grid pursuant to the terms and conditions of the ISO Tariff and the TO Tariff. Service hereunder shall not be available if the Commission would be prohibited from ordering such service under Section 212(h) of the Federal Power Act.[8]

SCE interprets the WDAT to require that every wholesale Distribution Customer (as defined by the WDAT) has equal access to SCE's Distribution System, as long as the customer is eligible for

[8] SCE's WDAT is publicly available here: https://www1.sce.com/nrc/openaccess/SCE_WDATCombinedFile_20150722.pdf (last checked Feb. 18, 2019). Additional information is available here: https://www.sce.com/business/generating-your-own-power/grid-interconnections/wholesale-distribution-access-tariff (last checked Feb. 18, 2019).

Distribution Service and completes the interconnection process as outlined in the WDAT. Riverside, as a municipal utility, is a wholesale Distribution Customer.

Q: ***Explain how a municipal utility would typically request an expansion of service from SCE pursuant to the WDAT.***

A: While each request for expansion of service is unique, SCE has a standardized process for evaluating a request from any wholesale Distribution Customer generally, and specifically any municipal utility that is a wholesale Distribution Customer. This process is outlined in several Sections of the WDAT and relevant Attachments and Appendices.[9] For example, Section 12 generally describes the nature of Distribution Service, and Section 12.14 specifically outlines the requirement that a wholesale Distribution Customer must annually submit a forecast to SCE of the customer's estimated future load, along with any timely notice of any material changes to that forecast. SCE then notifies the wholesale Distribution Customer about whether any studies are needed to determine the scope of work and costs associated with upgrades that would accommodate the increased load. Such studies typically include "System Impact Studies"[10] and "Facilities Studies."[11] Upon completion of any required studies, SCE would then look to enter into relevant agreements(s) with the wholesale Distribution Customer to engineer, procure, and construct any system upgrades or other required facilities that were identified in the studies needed to accommodate the increased load.

Section 15 of the WDAT outlines the procedures and processes for customers to request Distribution Service, generally providing that an Eligible Customer requesting service under the WDAT must submit an application which includes, among other things:

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[9] Please refer to SCE's internet references cited in footnote 8 above.

[10] WDAT § 2.29 defines "System Impact Study" as "An assessment by the Distribution Provider of (i) the adequacy of the Distribution System to accommodate a request for Distribution Service and (ii) whether any additional costs may be incurred in order to provide Distribution Service."

[11] WDAT § 2.13 defines "Facilities Study" as "An engineering study conducted by the Distribution Provider to determine the required modifications to the Distribution Provider's Distribution System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested Distribution Service."

1. a deposit;
2. the identity of the party requesting service;
3. the point of receipt/delivery;
4. a best estimate of the Wholesale Distribution Load to be served and the distribution voltage level;
5. a five (5) year forecast of monthly Wholesale Distribution Load requirements beginning with the first year after the service is scheduled to commence;
6. the amount and location of any interruptible loads included in the Wholesale Distribution Load; and
7. a description of any generation resources located within the distribution area.[12]

C. Description of Riverside's Request for Expanded Service

Q: Was the typical expansion of service request process followed with respect to RTRP?

A: Yes, while Riverside's expansion of service request was unique, at least in part because Riverside faces unique capacity and reliability challenges in comparison to other municipalities of similar size, Riverside's request for expansion of service followed SCE's generally expected practice. Riverside, which I understand until its installation of generation resources in recent years, had been exclusively dependent on SCE for power and has received power from SCE for many decades.

Pursuant to the operative interconnection arrangement prior to RTRP, SCE allocated two transformers at its Vista Substation, with up to 560 MVA of nameplate transformation capacity, exclusively to serve Riverside. The applicable transformers transform power from 230 kV transmission-level voltage to 69 kV subtransmission-level voltage for delivery into Riverside's service territory.

Riverside is currently served radially[13] from the CAISO-controlled transmission system through a single point (230 kV bus) at SCE's Vista Substation. Vista Substation is the *only* point of connection

[12] *See* WDAT §§ 15.1 – 15.7.

[13] Radial electrical systems are served through a single point of interconnection to an electric power source, such as the CAISO-controlled transmission grid. Power flows into radial electric systems but does not flow out.

between the CAISO-controlled transmission grid and Riverside's system. Therefore, any failure of the Vista Substation facilities serving Riverside would be catastrophic because it would render Riverside without power (except for power generated from Riverside's own peaker units constructed within the past 20 years). I understand that such localized generating facilities are of insufficient capacity to serve all of Riverside's load under a failure of facilities at Vista Substation. In addition, by 2000, the load forecasts provided by Riverside, as well as SCE's own analyses of projected future load, demonstrated that even assuming no loss of service from Vista Substation, electrical demand within Riverside's service territory was projected to exceed the Vista Substation transformation capacity dedicated to Riverside within a few short years.

Q: When was the first time Riverside's forecasts showed an exceedance?

A: Load forecast data provided by Riverside in late 2000 indicated that Riverside's electricity demands would exceed the capacity of the service provided *via* Vista Substation in 2007. SCE's own analysis of Riverside's historical load growth data likewise confirmed that an exceedance was expected.

Q: What did SCE do in response to indications that the capacity of service provided to Riverside at the Vista Substation would be exceeded?

A: Given that information, I am informed and believe that SCE staff undertook a series of studies and assessments at Riverside's request to determine what type of system upgrades could be implemented to meet Riverside's electrical load needs. SCE and Riverside ultimately proposed looping in the Mira Loma-Vista 230 kV No. 1 line into a new substation as the recommended method of service. The governing interconnection tariff for the high-voltage facilities in this method of service is SCE's Transmission Owner Tariff ("TOT"), and not SCE's WDAT tariff which governs the existing provision of 69 kV service. Further details on SCE's Integrated System Planning process are included in *SCE's Direct Testimony Regarding How RTRP Was Designed And Proposed To Serve The Public Convenience And Necessity In A Manner Consistent With Prudent Electric System Planning And Engineering Standards And The Qualifications Of Dana Cabbell*, below.

D. SCE's Transmission Owner Tariff and Interconnection Facilities Agreement Between Riverside and SCE

Q: Does the WDAT govern the construction of the high voltage facilities currently proposed as RTRP's Hybrid Route?

A: No. The CAISO operates the high voltage transmission systems within its jurisdiction, and the owners of those transmission systems (such as SCE) are subject to the CAISO's tariff. The interconnection of transmission facilities to the SCE-owned portion of the CAISO-controlled grid is governed by SCE's TOT. SCE's TOT describes the terms under which SCE provides open access to its transmission system to wholesale customers seeking to: (1) Interconnect generation facilities to SCE's transmission system to deliver energy and capacity services to the CAISO-controlled grid;[14] (2) Interconnect wholesale load to SCE's transmission system; or (3) Interconnect new transmission facilities to SCE's transmission system. SCE's TOT also sets revenue requirements and applicable rates and charges for transmission access over the CAISO-controlled grid and sets the terms and conditions for transmission expansion. Per the TOT, and relevant in the case of the RTRP, the costs of High Voltage Transmission Facilities[15] under CAISO's "Operational Control" are recovered via the High Voltage Access Charge ("HVAC"). In general, each Participating Transmission Owner ("Participating TO") is allowed to recover, and pays a share of, the HVAC proportional to its MWh of retail load. Both SCE and Riverside are Participating TOs, thus both pay for the costs of the HVAC in proportion to their loads, as do all other Load Serving Entities that use the high voltage CAISO-controlled grid.

Because RTRP proposes the installation of High Voltage Transmission Facilities, it is governed by the TOT and HVAC. Under the currently effective HVAC design, all users of the high voltage

[14] As stated in Section 8.1 of the TOT, requests for interconnecting new generation projects to SCE's transmission system, or modification to existing generation projects connect to SCE's transmission system, are administered by the CAISO through the CAISO's tariff.

[15] TOT § 3.41 defines "High Voltage Transmission Facility" as a "transmission facility under the operational control of the ISO that is owned by the Participating TO or to which the Participating TO has an Entitlement that is represented by a Converted Right and that operates at a voltage at or above 200 kilovolts, and supporting facilities, and the costs of which are not directly assigned to one or more specific customers."

CAISO-controlled grid would share the costs for the RTRP Hybrid Proposal in proportion to their use of the grid. Relevant here, the TOT provides, that the

> Participating TO's revenue requirements and applicable rates and charges for transmission access over the ISO Controlled Grid and the terms and conditions for transmission expansion and interconnection are set forth in this TO Tariff and the ISO Tariff.…
>
> Participating TOs are able to participate in the ISO and utilize the entire ISO Controlled Grid to serve their End-Use Customers. The applicable High Voltage Access Charges and Transition Charges shall be paid by Participating TOs to the ISO pursuant to the ISO Tariff. If a Participating TO utilizes the Low Voltage Transmission Facilities of another Participating TO, such Participating TO shall also pay the Low Voltage Access Charge of the other Participating TO.[16]

Q: Does the TOT obligate SCE to interconnect municipal utilities and/or other wholesale electricity customers?

A: Yes, if the wholesale interconnection is to the transmission system, but such interconnection must be consistent with, among other things, Good Utility Practice (as defined by SCE's TOT) and should not impair system reliability or adversely affect the ability of the Participating TO to honor its existing obligations. The TOT provides, in relevant part

> The Participating TO shall, at the request of a third party pursuant to Section 10 [Interconnection Process], interconnect its system to the wholesale generation or wholesale load of such third party, or modify an existing wholesale Interconnection. … Interconnection must be consistent

[16] SCE TOT § 1.1. SCE's TOT is publicly available here: https://www1.sce.com/nrc/openaccess/SCE_TOTCombinedFile_20150722.pdf (last checked Feb. 18, 2019). Additional information is available here: https://www.sce.com/business/generating-your-own-power/grid-interconnections/transmission-owner-tariff (last checked Feb. 18, 2019).

> with Good Utility Practice,[17] in conformance with all Applicable Reliability Criteria, all applicable statutes, regulations, and ISO reliability criteria for the ISO Controlled Grid. The Participating TO will not accommodate the Interconnection if doing so would impair system reliability, or would otherwise adversely affect the ability of the Participating TO to honor its Encumbrances[18] existing as of the time a party submits its Interconnection Application. The Participating TO shall identify any such adverse effect on its Encumbrances in the System Impact Study performed pursuant to Section 10.7. To the extent the Participating TO determines that the Interconnection will have an adverse effect on Encumbrances, the party requesting Interconnection shall mitigate such adverse effect.[19]

Q: Why did SCE and Riverside ultimately negotiate and execute an interconnection facilities agreement in support of RTRP?

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[17] SCE TOT § 3.37 defines "Good Utility Practice" as "[a]ny of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region."

[18] SCE TOT § 3.22 defines "Encumbrance" as a "legal restriction or covenant binding on the Participating TO that affects the operation of any transmission lines or associated facilities and which the ISO needs to take into account in exercising Operational Control over such transmission lines or associated facilities if the Participating TO is not to risk incurring significant liability. Encumbrances shall include Existing Contracts and may include: (1) other legal restrictions or covenants meeting the definition of Encumbrance and arising under other arrangements entered into before the ISO Operations Date, if any; and (2) legal restrictions or covenants meeting the definition of Encumbrance and arising under a contract or other arrangement entered into after the ISO Operations Date."

[19] SCE TOT § 8.1.1.

A: To design and construct RTRP's High Voltage Transmission Facilities, including the 230 kV Interconnecting Substation and line loop, the TOT requires the development and execution of an Interconnection Facilities Agreement ("IFA"). Specifically,

> a party requesting Interconnection shall request in writing that the Participating TO tender to such party an Interconnection Agreement that will be filed with FERC…. The Interconnection Agreement will include, without limitation, cost responsibilities and payment provisions for any engineering, equipment, construction, ownership, operation and maintenance costs for any Direct Assignment Facilities, any Reliability Upgrades, and for any other mitigation measures.[20]

An IFA was necessary to initiate the process for SCE to design and construct the substation and line loop-in and for the transfer of Riverside load to the new substation, to establish operational procedures associated with the energization and operation of the new substation and the terms and conditions necessary for Riverside to interconnect to SCE *via* RTRP.

I understand that on or about October 19, 2005, SCE and Riverside then entered into negotiations regarding the IFA, which included the licensing and development of RTRP. Ultimately, SCE and Riverside participated in a mediation before FERC, which resulted in the agreement and operative effect of the March 16, 2009 IFA. A true and exact copy of the March 16, 2009 IFA is attached hereto as Attachment A. The March 16, 2009 IFA was recently amended. A true and exact copy of the recently updated January 15, 2019 IFA is attached hereto as Attachment B.

Q: ***Was this material prepared by you or under your supervision?***

A: Yes.

Q: ***Insofar as this material is factual in nature, do you believe it to be correct?***

A: Yes.

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[20] SCE TOT § 8.1.3 (Interconnection Agreement).

Q: ***Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?***

A: Yes.

Q: ***Does this conclude your qualifications and prepared testimony at this time?***

A: Yes.

III.

SCE's Direct Testimony Regarding How RTRP Was Designed And Proposed To Serve The Public Convenience And Necessity In A Manner Consistent With Prudent Electric System Planning And Engineering Standards And The Qualifications Of Dana Cabbell [21]

Q: ***Please state your name and business address for the record.***

A: My name is Dana Cabbell, and my business address is 3 Innovation Way, Pomona, California 91768.

Q: ***Briefly describe your education, work history and present responsibilities at SCE.***

A: I graduated from California Polytechnic University, San Luis Obispo with a Bachelor of Science degree in Electrical Engineering in 1982. In 1989, I became a Registered Professional Electrical Engineer with the state of California. I have worked for Southern California Edison (SCE) for 36 years in the areas of transmission and distribution planning. Presently, I am the Principal Manager of the Integrated System Planning ("ISP") group for SCE. In this position, I'm responsible for providing a holistic view of the long-range planning for SCE's transmission and distribution systems, allowing for well-informed, strategic decisions regarding grid investments, integration of renewable/energy storage resources, enabling grid modernization, and resiliency efforts.

Q: ***Please describe your role with respect to the RTRP.***

A: As Principal Manager of the ISP Group, I lead a team of power system planners that perform the technical studies required to assess the future reliability/adequacy of SCE's electric grid. These technical studies also include evaluating service requests from SCE's wholesale customers, such as that requested by Riverside to address its increase in customer demand, and to evaluate a second point of interconnection with the SCE transmission system.

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[21] This section addresses Scoping Memo Issues ## 6 ("*To the extent that the proposed project and/or project alternatives results in significant and unavoidable impacts, are there overriding considerations that nevertheless merit Commission approval of the proposed project or project alternative?*") and 7 ("*Does the proposed project serve a present or future public convenience and necessity? This issue directly overlaps issue 6, above*.").

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony in this proceeding is to sponsor portions of *Southern California Edison Company's (U 338-E) Direct Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project* related to: (a) how RTRP was originally conceived and proposed for consideration by CAISO and the Commission; and (b) how RTRP is designed and proposed to serve the public convenience and necessity in a manner consistent with prudent electric system planning and engineering standards.

A. SCE's Review and Response to Riverside's Request for Expanded Service

Q: What steps did SCE take once Riverside's request for expanded service was received?

A: SCE's ISP group, in which I am a Principal Manager, performs the power system studies evaluating requests for expanded service by municipal utility customers. The roles of the ISP group include determining existing electrical facility limitations, evaluating option(s) to reliably serve the expanded service, and developing high-level cost estimates relative to the option(s) considered for expanded service. Such options(s) include viable electrical line configurations, substation transformer sizes, and substation configurations.

Based on my review of documents and discussions with my staff, I presently understand that Riverside's loads have exceeded the capacity provided by the two transformers at Vista Substation each year for over a decade, with Riverside only managing to accommodate that excess by relying on gas-fired peaker generation plants. These exceedances were predicted as early as September 2000, when Riverside notified SCE that its forecasted demand was estimated to exceed the Riverside-dedicated capacity at Vista Substation in or around 2007. SCE performed its own independent analysis of Riverside's estimated future demand, concurring that Riverside's demand was likely to exceed its dedicated capacity at the Vista Substation. SCE indicated that further studies would be required to verify the scope of potential solutions that could be implemented to provide expanded service to Riverside.

Over the course of the next six years, Riverside would request and support SCE's development of various System Impact and Facilities Studies to analyze potential methods of service to accommodate

Riverside's increasing demand, as well as mitigation measures to limit Riverside's dependence on Vista Substation as its sole source of power. Such efforts included, but were not limited to:

- On or about June 25, 2002, SCE completed a System Impact Study in support of Alliance Riverside, LLC's application, on Riverside's behalf, for the interconnection of 40 MW of generation at Riverside's Springs Substation. A Facilities Study for the Springs 40 MW Generation Project was subsequently completed on or about September 10, 2002. These studies were requested to determine any additions or upgrades of SCE facilities that would be required as a result of the 40 MW of additional generation within Riverside's service territory.
- On or about November 6, 2003, SCE completed a "Non-Tariff System Impact Study"[22] studying interconnection options to connect Riverside's electrical system directly to SCE's transmission system, such as: (1) looping in the Mira Loma-Vista No. 1 230 kV Transmission Line into a new 230/69 kV substation; and (2) Riverside building two new 230 kV transmission lines from Riverside's proposed Jurupa 230/69 kV Substation and interconnecting said proposed transmission lines at SCE's Mira Loma Substation and SCE's Vista Substation. A Facilities Study for Alternative 1 was subsequently completed on or about May 6, 2004.
- On or about May 11, 2005, SCE completed a "System Impact and Operational Combined Study Transmission Assessment" to identify impacts associated with the interconnection of Riverside's Riverside Energy Resource Center ("RERC") Project. The RERC Project proposed to connect 96 MW of gas turbine generation at Riverside's RERC Substation. This Study was requested to determine any additions or upgrades of SCE facilities that would be required as a result of the 96

[22] A "non-tariff" system impact study is an informal assessment of potential impacts to SCE's system considering the proposed interconnection without reference to other contemplated interconnections that may be planned and are part of an existing queue or interconnection process. Although such an informal study may be helpful to ascertain some of the potential effects of the proposed interconnection, informal system impact studies are typically not viewed as reliably sufficient to contemplate all potential impacts.

MW of additional generation within Riverside's service territory. The Facilities Study in support of the RERC was transmitted to Riverside and accepted on or about October 19, 2005.[23]

- On or about June 7, 2005, SCE completed a System Impact Study in support of Riverside's request for a 230 kV Transmission Interconnection to SCE's Mira Loma-Vista No. 1 230 kV line from Riverside's proposed Jurupa 230/69 kV Substation. As a tariff-based study, this System Impact Study incorporated information from other generation and transmission interconnections pending in the SCE queue. This System Impact Study considered three options: (1) Loop the existing Mira Loma-Vista No. 1 230 kV line by building 8.25 miles of new 230 kV double-circuit transmission line from the existing Mira Loma-Vista No. 1 230 kV transmission line right-of-way to into a new 230 kV SCE interconnection facility adjacent to Riverside's proposed Jurupa Substation in Riverside; (2) Build a 230 kV SCE interconnection facility located adjacent to Riverside's proposed Jurupa Substation in Riverside with two new 230 kV lines, one from each of SCE's Mira Loma and Vista Substations to the new Jurupa Substation; (3) Build a new SCE 230 kV interconnection facility adjacent to the existing Mira Loma-Vista No. 1 230 kV transmission line right-of-way with new 8.25 miles of double-circuit 230 kV transmission line to Riverside's proposed Jurupa Substation in Riverside. Option (1) was identified as the preferred alternative and would eventually become known as the RTRP for which SCE submitted its Application to the Commission in this proceeding. A Facilities Study for this work was subsequently completed on or about September 27, 2005 to determine the scope of work and associated costs required for the construction of Option (1). The results of the June 7, 2005 System Impact Study and the September 27, 2005 Facilities Study were shared with Riverside, which accepted the Studies' respective findings. True and exact copies of the June 7, 2005

[23] On or about April 13, 2009, SCE initiated a System Impact Study in response to Riverside's request to add an addition of approximately 96 MW of generation ("RERC 2") to the existing interconnection. The Facilities Study in support of RERC 2 was published on or about September 28, 2009.

System Impact Study and the September 27, 2005 Facilities Study referenced above are attached hereto as Attachments C and D.

Q: What other non-transmission voltage alternatives did SCE and Riverside consider during that time?

A: As indicated above, SCE's ISP Group considered a number of options and performed various studies in response to Riverside's projected electrical demands and growth. I understand that SCE also considered options that included, among other things:

- adding an additional transformer to the Vista Substation's "A" Bus Section and then transferring some of Riverside's distribution substations from the Vista Substation "C" Bus Section (which was and remains entirely dedicated to Riverside) to the "A" Bus Section (which serves SCE retail load, as well as the City of Colton's Municipal Utility ("Colton Electric")), along with a re-configuration of Riverside's 69 kV system;
- adding an additional transformer to the Vista Substation in such a way that the "C" Bus Section would have three transformers and the "A" Bus Section would remain with only one transformer; and
- electrically paralleling the Vista Substation's "A" and "C" Bus Sections.

Q: Why was additional transformation capacity at Vista Substation not pursued to address Riverside's projected electrical demand and growth?

A: Additional transformation capacity was in fact added to the Vista Substation's "A" Bus Section bringing the number of transformers to two and the capacity of the "A" Bus Section to 560 MW (up from 280 MW) in or around October 2006. However, this additional transformation capacity was pursued to address a need for expanded service to accommodate SCE retail load, as well as anticipated load from Colton Electric which, as mentioned previously, is served from SCE's "A" bus section at Vista Substation. This addition occupied the last available space for 230/69 kV transformer capacity at Vista Substation and precluded further opportunities to expand transformer capacity dedicated solely to Riverside.

The current 230 kV switchrack is a 12 position double-bus-double-breaker configuration which is capable of accommodating up to 12 connected elements. It is now fully occupied, connecting six 230 kV lines and six transformer banks (four 230/69 kV and two 230/115 kV).

Q: Why can't Vista Substation be expanded to provide space for additional transformer capacity?

A: Vista Substation cannot be expanded due to physical constraints and limitations present at the site. Specifically, Vista Substation is situated on a hill with significant slopes to the east and north. The substation is bordered by Interstate 215, Grand Terrace Road, Newport Avenue, and residential developments.

The 230 kV switchrack is arranged north to south. Immediately to the north of the 230 kV switchrack is the substation property line and Grand Terrace Road with residential homes on the opposite side of the street. Directly to the south of the 230 kV switchrack is the C Bus Section of the 69 kV switchrack, followed by Newport Avenue and then Interstate 215. Immediately to the east of the 230 kV switchrack is the 115 kV switchrack, followed by a steep downward slope and abutting retaining wall and then Interstate 215. Immediately to the west of the 230 kV switchrack are the four 230/69 kV transformers, followed by the A-section bus, transmission towers, control buildings, SCE's property line, and then residences and a steep downward slope. There is no room for expansion to accommodate an additional 230 kV switchrack position to terminate a new 230/69 kV transformer at the substation. Additionally, there is insufficient space (west to east) to convert the double-bus-double-breaker configuration into another configuration (such as breaker-and-a-half) in an attempt to allow for additional 230 kV connections.

An aerial depiction of Vista Substation and relevant constraints is attached hereto as <u>Attachment E</u>. Please also refer to the RTRP Lower Voltage and Other Design Alternatives Report, Section 3.4.2.1.

Q: Is the additional capacity of Vista Substation's "A" Bus Section sufficient to address the objectives of RTRP?

A: No. Based on my review of the files and discussions with my staff, an approach whereby Riverside load would be permanently moved from the C Bus Section to the A Bus Section was likely dismissed from consideration for various reasons, including the fact that such an approach would have only provided a short-term, temporary solution to Riverside's projected capacity shortfalls given the growth anticipated on both SCE's and Riverside's systems. Since that time, SCE has not evaluated such an alternative in detail, but I believe that such a solution would:

- still only temporarily address the capacity deficits facing Riverside;
- require continued operation and reliance on Riverside's gas-fired generation; and
- as explained below, not provide a second point-of-service consistent with most other similarly sized publicly owned utilities to maintain/improve reliability, resiliency, and operational flexibility.

For these primary reasons, my group and I do not anticipate that permanently moving 69 kV circuits from the C Bus Section to the A Bus Section in order to theoretically increase Riverside's allocation of the capacity of Vista Substation is a viable solution to Riverside's needs and/or the objectives of RTRP.

Q: Why was reconfiguring the Vista Substation in such a way that the "C" Bus Section could have three transformers dismissed from consideration?

A: As noted above, the Vista Substation "A" and "C" bus sections now have two transformers each and there is no space for additional transformation capacity due to physical site constraints as well as the fact that adding another 230/69 kV transformer would require an additional connection to the 230 kV bus, which is fully built-out with all positions occupied and cannot be further expanded due to physical property constraints. The option contemplated above assumes that instead of the "A" and "C" bus sections each having two transformers, that one of the transformers on the "A" bus section which currently serves Colton Electric and SCE retail load would be instead attached to the "C" bus section, which is dedicated to serve Riverside's load. This would result in a configuration where three transformers are situated on the "C" Bus in support of Riverside's load, leaving only one transformer on the "A" Bus to serve Colton Electric and SCE's local retail load.

The system configuration contemplated above would result in three 230/69 kV transformers electrically connected in parallel on the Vista Substation "C" bus section. As such, the rated short-circuit current (or "short circuit duty") interrupting capability of all 69 kV CBs on the "C" bus section, as well as the rated capability of the Vista Substation ground grid,[24] would be exceeded. The short circuit duty value at Vista Substation with three transformers in parallel is calculated to exceed 50 kA. This value exceeds not only SCE's maximum standard rating for 69 kV CBs, but also that of the maximum industry standard CBs at this voltage. If the short-circuit duty exceeds CB and ground grid capabilities, then in the event of a fault, electrical current would continue to flow through the substation equipment and would not be interrupted. This may damage substation equipment and cause significant hazards, including arcing and fires, threatening the safety of personnel inside the substation at the time.

In summary, such a configuration would violate SCE and industry standards for the safe and reliable operation of the Vista Substation. For additional information, please refer to the true and exact copy of SCE's response to Cal. Advocates Data Request 3, Question 5 attached hereto as Attachment L.

Further, even if this alternative were consistent with safe and prudent electrical planning and/or industry practices (which it is not), average load growth on SCE's system at Vista Substation suggested that this approach would simply transfer Vista Substation's capacity shortfall from the "C" bus to the "A" bus.[25] In turn, this would likely have required SCE to propose an additional project in the near future to accommodate the lack of capacity on the Vista "A" bus section serving SCE's retail load and Colton Electric.

In addition, this alternative would result in serving both Colton Electric and SCE's retail load through a single transformer on the Vista "A" Section. This would subject all of the customers served

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[24] A ground grid is an underground grid of bare copper wire buried approximately two feet underneath substation property for the purpose of protecting personnel and equipment by providing a low-resistance path (to ground) for hazardous conditions such as electrical short circuits or over-voltage conditions due to faults or lightning strikes. These grids are typically installed during substation construction and are very difficult to safely upgrade in an energized substation.

[25] SCE's 2003-2013 forecast data projected the Vista Substation A and C bus sections would grow 2.1% annually, suggesting that the available capacity left on the single 280 MVA transformer serving Colton Electric and SCE retail load would have resulted in an exceedance in year 2004. True and exact copies of excerpts from SCE's 2003 A-bank Substation Plan with the anticipated load growth as of 2003 are attached hereto as Attachment F.

from the "A" Bus Section to loss of service during an unplanned outage of the single transformer. Additionally, serving a bus section of load at a substation with a single transformer presents significant challenges to performing routine maintenance and inspections on the transformer (which require the transformer to be de-energized) without a second transformer in-service. SCE does not typically serve such a large amount of load through a single transformer without sufficient backup available to ensure reliable service to load in the event of a transformer failure. In contrast with that principle, the configuration identified here decreases reliability and creates the potential for a single point of failure for *all* load served out of the Vista "A" Section.

For these main reasons, SCE does not believe the parallel operation of three transformers on the Vista "C" bus section in order to theoretically increase Vista Substation's load serving capacity to Riverside is a viable solution to Riverside's needs and/or the objectives of RTRP.

Q: Why was reconfiguring the Vista Substation in such a way that the Vista "A" and "C" Sections would operate in a parallel manner dismissed from consideration?

A: "Paralleling" the Vista "A" and "C" bus sections (which today have two transformers each) would result in a configuration where all four 230/69 kV transformers are situated on a connected and common bus section comprised of the "A" and "C" bus sections. The paralleled system configuration contemplated here could be achieved through closing the bus sectionalizing CBs between the Vista "A" and "C" 69 kV bus sections. In theory, this common bus section would serve all of the 69 kV load out of the Vista Substation, including that of Riverside, Colton Electric, and SCE's retail customers.

Again however, like the three/one system configuration contemplated above, the short circuit duty rating of all forty-six 69 kV CBs and rated capability of the Vista Substation ground grid would be exceeded. The short-circuit duty value at Vista Substation with all four transformers in parallel exceeds SCE and industry standards for the safe and reliable operation of the Vista Substation.

In addition to these concerns, operating the Vista "A" and "C" bus sections in parallel would result in a common 69 kV bus for which system events (*e.g.*, faulted conditions, voltage fluctuations, *etc.*) on the SCE, Riverside, and/or Colton Electric systems would be experienced across all three systems due to the common interconnected 69 kV "A" and "C" bus section configuration. Thus, operating the Vista "A" and "C" bus sections in parallel would reduce reliability for all customers (SCE's, Riverside's, and Colton Electric's) served out of the common Vista Substation 69 kV bus.

Even assuming all needed and theoretical upgrades were implemented to make this parallel operation possible, and the risk that disturbances on one system would reverberate through all three could be ignored, such a solution would still:

- only temporarily address the capacity deficits facing Riverside;
- require continued operation and reliance on Riverside gas-fired generation;
- adversely impact reliability to SCE's, Riverside's, and Colton's customers; and
- would not provide a second point-of-service consistent with other most similarly sized publicly-owned utilities to maintain/improve reliability and operational flexibility.

SCE does not believe parallel operation of the Vista "A" and "C" bus sections in order to theoretically increase Vista Substation's load serving capacity is a viable solution to Riverside's needs and/or the objectives of RTRP.

Q: What other 230 kV transmission line alternatives did SCE and Riverside consider in addition to the option that became RTRP?

A: SCE's ISP Group also considered a number of 230 kV transmission options in response to Riverside's projected electrical demands and growth. Certain options were considered as part of the System Impact Studies referenced above. I understand that SCE also considered options that included, among other things:

- Construction of a new a new 230/69 kV substation near "Agua Mansa," in SCE's service territory to the northeast of Riverside;
- Looping an existing SCE line into and out of a new 230/69 kV substation (then referred to as the "Jurupa Substation") to be owned and operated by Riverside;
- Build a 230 kV SCE interconnection facility located at Riverside's new Jurupa Substation with two new 230 kV lines, one each from the Mira Loma and Vista substations to the new Jurupa Substation. This option was considered in the June 7, 2005 System Impact Study and also

presented as for CAISO's consideration as "Option 2" in CAISO's June 7, 2006 internal Memorandum to its Operations Committee; and

- Build a new SCE 230 kV interconnection facility adjacent to the existing Mira Loma-Vista No. 1 transmission line 230 kV right-of-way with new 8.25 miles of double-circuit 230 kV transmission to a new Riverside 230/69 kV Jurupa Substation. This option was considered in the June 7, 2005 System Impact Study and also presented as for CAISO's consideration as "Option 3" in CAISO's June 7, 2006 Memorandum.

Q: Why was the construction of a new SCE substation near Agua Mansa dismissed from consideration?

A: An alternative contemplating a second substation with a capacity similar to that of the Vista Substation was considered near "Agua Mansa" – an area in SCE's service territory to the northeast of Riverside. This alternative was dismissed from further consideration as it would not have been proximately located near either SCE or Riverside's load centers. In contrast, RTRP as proposed is located geographically near where I understand Riverside's system load to be expanding.

Q: Why was looping in and out of a new substation owned and operated by Riverside dismissed from consideration?

A: This option was apparently briefly considered but Riverside did not specifically request that SCE perform studies on any such alternative as the physical configuration of such an alternative would be substantially similar (if not the same as) to RTRP as proposed, with the exception of the location of the new SCE's 230 kV switching station. It is my understanding that Riverside's consideration of such an option stopped once it became apparent to Riverside that Riverside would have the obligation to build 230 kV infrastructures to interconnect to SCE's Mira Loma and Vista Substations but would not retain the ownership and operational control of such facilities, as the 230 kV portion of any line, as well as any portion of the 230 kV substation equipment associated with such a line loop-in, would still be required to be owned, operated and maintained by SCE.

Q: Why were Options 2 and 3, noted above as referenced in CAISO's June 7, 2006 internal Memorandum to its Operations Committee dismissed from consideration?

A: SCE considered both Options 2 and 3, but found Option 1 (the alternative which eventually became proposed as RTRP) to be preferred:

> Two other line configurations were considered (Option 2), which entailed two additional 220 kV transmission lines to be built from both, Mira Lama and Vista substations to the new Jurupa substation. However Option 2 proved to be disproportionately expensive and not a feasible option due to the physical limitation at the Vista 220 kV bus. The third option (Option 3), considered the possibility of building another new substation in-between the Mira Lorna and Vista substations. This new substation would then serve the City's new Jurupa substation. This option was also disproportionately expensive and therefore the preferred line configuration was the City's proposal of looping in the existing Mira Loma-Vista 220 kV line into the City's new Jurupa Substation….
>
> RECOMMENDATION
>
> Option 1 details the loop-in of the Mira Lorna- Vista 220 kV line #1 into the new Jurupa Substation is the recommended method of service in 2008. This option is consistent with SCE's planning practices to address load growth in the area. The option provides adequate reliability to serve the Riverside and is also the most economically feasible alternative.

See Attachment C at 4-5 (SCE's June 7, 2005 System Impact Study).

Q: Please explain why Option 1 included the construction of two separate substations?

A: As referenced above with respect to the possibility of Riverside ownership and operation of a new 230 kV substation connected with SCE's electrical grid, the two substations (now the Wildlife (SCE's) and Wilderness (Riverside's) Substations) are needed to delineate point of change of ownership and to ensure that SCE has control of the 230 kV lines connected to its system. When SCE "loops" lines into a new substation, SCE needs to be able to operate, maintain and control CBs at each of the ends of the lines created by the loop. This is to ensure the reliability of SCE's 230 kV system.

In the case of RTRP, the 230 kV switchrack will belong to SCE, but the 230 kV/69 kV transformers and 69 kV switchrack belong to Riverside. Notably, however, if the proposed Wilderness/Wildlife Substations were being built to service SCE's load only (instead of Riverside's), the constructed components would look substantially similar to what is being proposed for RTRP. Potential exceptions to this being: (1) there would be no fence in the middle of the property delineating SCE's ownership from Riverside's ownership; and (2) RTRP's proposed two separate control rooms would likely be combined into one single, slightly larger control room.

B. <u>CAISO's Review and Concurrence With The Proposed Solution - RTRP</u>

Q: Explain how the California Independent System Operator ("CAISO") became involved in the considerations regarding Riverside's request for an additional connection at 230 kV.

A: SCE's Transmission System is controlled by the CAISO, while SCE's Distribution System is controlled by SCE. The line of demarcation between the CAISO and SCE controlled systems (with certain exceptions) is 230 kV, with CAISO control of facilities at or above 230 kV and SCE control of facilities below 230 kV. Therefore, the 69 kV lines that feed Riverside's system from Vista Substation are *not* CAISO controlled; they are part of SCE's Distribution System.

SCE routinely informs CAISO of studies developed in response to official interconnection requests potentially implicating CAISO jurisdiction. Because the June 7, 2005 System Impact Study and the September 27, 2005 Facilities Study contemplated 230 kV facilities, CAISO's jurisdiction was implicated and I understand CAISO was provided copies of said Studies.

On or about November 29, 2005, CAISO informed SCE that it had reviewed the September 27, 2005 Facilities Study and asserted, in relevant part that

> CAISO concurred with the [System Impact Study] conclusion and the SCE recommendation to interconnect the new substation by loop-in of the Mira Loma-Vista 220 kV Line #1, described as Option 1… CAISO concurs with the facilities required and will recommend approval to interconnect the Project subject to completion of the facilities and scope of work identified in the Facilities Study and that the City of Riverside shall

> not parallel the facilities served by the Jurupa Substation with any other electrical facilities served by SCE or others… Since the estimated cost of this Project is in excess of $20 million, this Project will require CAISO Board's approval… CAISO management will recommend approval of Option 1 to its Board based on [a] revised cost estimate; and subject to SCE and the City of Riverside's management providing CAISO with a letter of agreement that both support the proposed Project Facilities.

A true and exact copy of CAISO's November 29, 2005 correspondence is attached hereto as Attachment G.

On or about May 3, 2006, SCE sent correspondence to CAISO supporting RTRP and formally requesting that CAISO's Board approve the Project. A true and exact copy of SCE's May 3, 2006 correspondence is attached hereto as Attachment H. Similarly, on or about May 9, 2006, Riverside also sent correspondence to CAISO asserting it "supports and requests the [CAISO] Board approve the proposed 230 kV Interconnection Project." A true and exact copy of Riverside's May 9, 2006 correspondence is attached hereto as Attachment I.

On or about June 7, 2006, CAISO's Operations Committee recommended that the CAISO Board of Governors approve

> the City of Riverside Transmission Project (Option 1…) as a necessary and cost effective addition to the ISO Controlled Grid and directs [SCE] to complete the construction of the City of Riverside Transmission Project as soon as possible and preferably no later than Q2, 2008.

See Attachment J (CAISO's June 7, 2006 Memorandum, at p. 2).

The same memorandum also noted

> SCE studies concluded that Options [*sic*] 2 was impractical [not feasible due to physical limitation at the Vista 230 kV bus] and Option 3 cost higher than Option 1. Option 1 would have no adverse system impacts and no system upgrades are necessary other than those facilities necessary to

> loop the Mira Loma-Vista #1 230 kV transmission line and the SCE constructed 230 kV substation.

Id.

Q: What were CAISO's determinations regarding Riverside's request for an additional connection at 230 kV?

A: The CAISO reviewed SCE's studies, and at its June 14, 2006 meeting, the CAISO Board voted to:

> grant its approval of: the City of Riverside Transmission Project (Option 1 as described in this Memorandum dated June 7, 2006) as a necessary and cost effective addition to the ISO Controlled Grid and Directs Southern California Edison (SCE) to complete the construction of the City of Riverside Transmission Project as soon as possible and preferably no later than Q2, 2009.

A copy of the CAISO Board meeting minutes documenting that vote is attached hereto as Attachment K.

C. Reasonableness of Riverside's Request for Expanded Service, and Consistency with SCE's Planning Standards

Q: In SCE's opinion, is Riverside's request for expanded service reasonable?

A: Yes, I believe that Riverside's request is reasonable, given what I understand to be Riverside's forecasted need, the information in the studies SCE's Integrated System Planning group performed, as well as the historical outages which affected service from SCE to Riverside[26] and SCE's estimation of challenges associated with providing reliable electrical service to serve the whole of Riverside's needs through Vista Substation in the future. Riverside faces unique capacity and reliability challenges in

[26] There were significant unplanned outages affecting Vista Substation on July 3, 2005 and October 26, 2007 resulting in the loss of SCE's ability to serve Riverside's load. Relevant information regarding these outages is included within SCE's response to Cal. Advocates' Data Request 3, question 6, and Data Request 4, question 5, a true and exact copy of which is included with Attachment L hereto.

comparison to other municipalities of similar size and Riverside's request for expanded service is generally consistent with SCE's interconnection/planning practices.

Q: What about the challenges facing Riverside make their circumstances unique?

A: SCE surveyed certain data regarding electric load serving entities ("LSEs") in California. According to the data SCE reviewed, as of 2015 there are a total of fifty-six (56) LSEs in California (including investor-owned utilities ("IOUs"), publically-owned utilities ("POUs"), municipal utilities, *etc*.). Of these fifty-six LSEs, five (5) have peak demands of approximately 3,000 MW or greater: Pacific Gas & Electric ("PG&E"), SCE, San Diego Gas & Electric ("SDG&E"), Los Angeles Department of Water and Power ("LADWP"), and the Sacramento Municipal Utility District ("SMUD"). The majority of the remaining LSEs are relatively small electric utilities with peak demands less than 200 MW (such as the City of Colton as described prior in testimony, which has approximately 85 MW of load). As presented in Table 1 below, there are eleven (11) LSEs, including Riverside, with between 200 MW and 3,000 MW of peak load demand. Of the eleven (11) LSEs in this category, only Riverside, Anaheim Public Utilities ("APU"), and Pasadena Water and Power ("PWP") are served by a single point of interconnection to a transmission provider.[27]

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[27] APU is connected to SCE's electrical grid *via* Lewis Substation. PWP is connected to SCE's electrical grid *via* Goodrich Substation.

Table 1. California LSEs between 200 MW and 3,000 MW of Peak Load [28]

Line #	Load Serving Entity	Peak Load (MW) (approx 2017)	Metered Customers (approx)	Number of Interconnection Points	Voltage of Interconnection
1	Imperial Irrigation District	1,000	145,000	>1	230 kV
2	Modesto Irrigation District	675	125,000	>1	230 kV
3	Riverside Public Utilities	640	110,000	1	69 kV
4	Turlock Irrigation District	600	100,000	>1	230 kV
5	Anaheim Public Utilities	600	120,000	1	230 kV
6	Silicon Valley Power	590	55,000	>1	115 kV
7	Roseville Power	400	60,000	>1	230 kV
8	Pasadena Water and Power	300	65,000	1	230 kV
9	Burbank Water and Power	280	55,000	>1	230 kV
10	Glendale Water and Power	275	90,000	>1	69 kV
11	Redding Electric Utility	230	45,000	>1	230 kV

There are significant differences between Riverside and APU or PWP relating to how service from SCE is obtained, and those differences highlight Riverside's unique needs that support the need for the second point of interconnection proposed *via* RTRP. For example, APU and PWP own the transformers at the substations serving them, and can therefore control how those transformers are operated, how maintenance outages are coordinated and how any expansions of service would be undertaken. In contrast, the transformers at Vista Substation serving Riverside are owned and operated by SCE, and thus Riverside has no control over balancing the capacity, maintenance, and/or expansion of the transformation capacity at Vista Substation.

[28] Information regarding electric load serving entities ("LSEs") in California is available at the California Energy Commission website here: https://www.energy.ca.gov/almanac/electricity_data/utilities.html (last checked February 23, 2019). Specifically, a list of California LSEs is available here: https://www.energy.ca.gov/almanac/electricity_data/utilities.html#public and electrical load data for each LSE is available here: https://www.energy.ca.gov/almanac/electricity_data/2012_LSE_peak_loads_GWh_requirements.xlsx.

Metered Customers and Number of Points of Service for LSEs were determined by reviewing the LSEs respective Integrated Resource Plans ("IRPs") and/or the LSE's websites. Loads were determined by the electrical load data from 2012 hyperlinked above and/or by reviewing the LSE's IRP.

Further, APU is served by 230 kV transmission service *via* four 230 kV lines into Lewis Substation and PWP is served by two diverse 230 kV lines into Goodrich Substation. In contrast, Riverside is served by 69 kV subtransmission lines from Vista Substation. Subtransmission service at 69 kV is not equivalent to the delivery of service at the 230 kV transmission level from either a capacity perspective or a reliability perspective. Higher voltage systems most often have a higher capacity to deliver power and may generally be considered to have better reliability performance as compared to the lower voltage systems. This is primarily due to the higher voltage systems being commonly constructed in dedicated right-of-ways and using taller and more robust supporting structures.

In contrast, lower voltage systems generally have lower capacity to deliver power, and it is more common that the lower voltage systems are constructed using shorter structures which follow roadways with vehicular traffic and thus their exposure to outages is typically greater than the transmission facilities resulting in the potential for decreased reliability. To deliver an equal amount of power, lower voltage systems require more lines than higher voltage systems. More lines means more congestion on the finite egress routes to and from a given substation, and even if such routes are available, lower voltage systems have increased exposure to issues that could adversely impact reliability. Thus, SCE considers the challenges facing Riverside's reliable provision of electrical service to be unique when compared with other approximately equivalently-sized California LSEs in that it is the only such LSE with one point of interconnection that is facing significant capacity shortfalls.

Lastly, Riverside's capacity shortfall is relatively unique among the eleven similarly situated LSEs. For example, APU is not facing a capacity shortfall. APU is served by four 280 MVA 230/69 kV transformer banks at Lewis Substation, providing a total of 1,120 MVA of transformer capacity - approximately twice the amount of APU's peak load demand, even today. In contrast, bearing out what was forecast back as early as 2000, Riverside's loads have exceeded the capacity provided by the two transformers at Vista Substation each year for over a decade, and Riverside has only managed to accommodate that excess by relying on gas-fired peaker generation plants it constructed within the past 20 years.

Q: ***Is RTRP consistent with SCE's system design for other radial electrical systems of similar size within SCE's service territory?***

A: Yes, RTRP is consistent with what would likely be SCE's system design for an electrical system of similar size within its own service territory. SCE's service territory has fifty-two (52) distinct radial electrical systems, each served by a single point of service at 230 kV from the CAISO-controlled grid. Riverside is one of these distinct radial systems. Of these fifty-two distinct radial systems, all but two, Riverside and Valley South, have external tie-lines.[29]

Compared against "networked" electrical systems, radial systems are generally less expensive and less complex to plan for and operate. However, without adequate system tie-lines between adjacent systems, a radial system is potentially subject to service interruptions if there is an outage at its primary point of interconnection to the bulk transmission grid. Such system tie-lines allow some or all of the load in each radial system to be picked up by adjacent systems in order to mitigate service interruptions.

As noted above, Riverside is one of these distinct radial systems served by SCE. However, the Riverside-owned 69 kV system is a radial system *without* external system tie-lines to adjacent electrical systems. Further, Riverside is served at a subtransmission voltage (69 kV) and thus does not own or control the upstream transformation or transmission facilities that serve it at Vista Substation. The delivery of power through 69 kV lines is necessarily constrained (for reasons identified above) in a way that delivery of power through higher voltages (*e.g.*, 115 kV, 230 kV or 500 kV) is generally not.

Q: ***Do you believe that there continues to be a need for the RTRP project, including a second point of interconnection from SCE, and that need demonstrates overriding considerations warranting approval of RTRP?***

A: Yes, there were significant unplanned outages affecting Vista Substation on July 3, 2005 and October 26, 2007 resulting in the loss of the ability to serve load. These outages affected Riverside's customers, with the 2007 outage impacting all of the Riverside. The July 3, 2005 outage was caused by

[29] SCE's Alberhill System Project (A.09-09-022) currently before the Commission is proposed to develop external tie-lines to the Valley South system.

a vehicle hitting a guy stub pole. The October 26, 2007 outage was caused when a switch failed on SCE's Highgrove-Pepper 115 kV Line, causing other lines and SCE's Highgrove Substation East 115 kV Bus to relay.[30] This also caused the Vista Substation 6A 230/115 kV transformer bank to relay on overload. The outage event then caused all seven 69 kV lines serving Riverside to relay resulting in a complete loss of power to Riverside.

Notably, prior to both outages, the Vista 230/69 kV System was in a normal state, meaning all equipment associated with the Vista 230/69 kV busses were in-service and the system was not in an abnormal configuration.

The July 3, 2005 event took approximately 2 hours for SCE to restore full service to those affected Riverside customers. The October 26, 2007 event took approximately 3 hours and 45 minutes for SCE to restore service to Riverside.

For additional information, please refer to SCE's responses to Cal. Advocates' Data Request 3, Question 6, and Data Request 4, Question 5, attached hereto as Attachment L.

Q: ***Was this material prepared by you or under your supervision?***

A: Yes.

Q: ***Insofar as this material is factual in nature, do you believe it to be correct?***

A: Yes.

Q: ***Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?***

A: Yes.

Q: ***Does this conclude your qualifications and prepared testimony at this time?***

A: Yes.

[30] A protection "relay" is assigned to specific substation equipment in order to monitor its attributes (voltage, frequency, status, etc.), ensuring that they stay within a specific range. Equipment "relays" when its attributes stray out of the specified range and a signal is sent from the relay to open the circuit breakers protecting that equipment.

IV.

SCE's Direct Testimony Regarding The Maximum Prudent And Reasonable Cost Of RTRP And The Estimated Cost Of The Project Alternatives And The Qualifications Of Kathy Hidalgo[31]

Q: ***Please state your name and business address for the record.***

A: My name is Kathy Hidalgo, and my business address is 2 Innovation Way, Pomona, California.

Q: ***Briefly describe your education, work history and present responsibilities at SCE.***

A: I received my Bachelor's Degree in electrical engineering from Virginia Polytechnic Institute and State University and my Master's Degree in business administration from the University of Maryland at College Park. In addition, I hold a Project Management Professional credential from Project Management Institute. My professional background includes over six years of service in project management organizations at SCE and over 20 years of experience in engineering, technical and project management, business process management, and project controls with various aerospace and defense companies. I am responsible for managing the project cost control team for major projects and transmission and substation projects.

Q: ***Please describe your role with respect to the RTRP.***

A: I am a Principal Manager in the Major Projects Organization within SCE's Transmission and Distribution Operating Unit. My responsibilities include the oversight and management of project and strategic controls functions including the development, management, and reporting of major project and program estimates, schedules, and total costs throughout the project and program lifecycles.

Q: ***What is the purpose of your testimony in this proceeding?***

A: The purpose of my testimony in this proceeding is to sponsor portions of *Southern California Edison Company's (U 338-E) Direct Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project* related to: (a) the

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31 This Section addresses Scoping Memo Issues ## 5 ("*Are the mitigation measures or project alternatives infeasible? This issue encompasses consideration of community values pursuant to Pub. Util. Code § 1002(a)(1)*") and 8 ("*What is the maximum prudent and reasonable cost of the project? (See Pub. Util. Code § 1005.5.)*").

estimated cost to construct RTRP; and (b) the estimated costs of the Project alternatives examined in the 2018 Final Supplemental Environmental Impact Report ("FSEIR") for the Project. Coupled with the facts before the Commission and environmental documents developed pursuant to the California Environmental Quality Act ("CEQA"), my testimony will serve as the factual basis upon which SCE will base legal arguments alleging the alternatives considered in the FSEIR, including Alternative 1 which was designated as the environmentally superior project alternative, are infeasible as a matter of public policy.

A. Summary of SCE's Estimated Costs for the Proposed Project and FSEIR Alternatives

Q: What are the total costs for the Proposed Project?

A: As shown in Table 2 herein, the cost estimate for the Proposed Project, SCE's "Hybrid" Route, is $414 million in 2018 constant dollars.

Q: Why are the estimated costs in this testimony provided in 2018 constant dollars?

A: SCE updated the previously provided 2015 constant dollar estimate to 2018 constant dollars to compare the cost differences on the same constant dollar basis. This comparison is shown in Table 2. The updated cost estimates are based on current estimating information.

Q: How does SCE convert RTRP's actual costs into 2018 constant dollars?

A: Consistent with SCE's request in A.05-04-018 (DPV2), and the resulting Commission decision (D.07-01-040), SCE proposes the use of both deflationary (to convert future year expenditures into 2018 constant dollars) and inflationary (to convert incurred costs in the prior years to 2018 constant dollars) factors to convert actual incurred costs to date to their equivalent value in 2018 constant dollars. A copy of the relevant Transmission inflation and deflation Indices in 2018 dollars used by SCE is attached hereto as Attachment M.

Table 2. Comparative Summary of Cost Estimates for RTRP Alternatives

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	2015 CPCN application	CPCN application 2018 Constant	SCE Hybrid 2015 Constant	Updated SCE Hybrid 2018 Constant	Alternative 1 2018 Constant	Alternative 2 2018 Constant	Alternative 3 2018 Constant	Alternative 4 2018 Constant
		No UG	~2.05mi UG	~2.05mi UG	~4.03mi UG	~4.06mi UG	~2.29mi UG	~2.88mi UG
Network Upgrades (SCE):								
Prelim. Engineering, Licensing & Permitting	$5	$20	$7	$20	$20	$20	$20	$20
Substation	15	19	15	19	19	19	19	19
Wildlife	*15*	*18*	*15*	*19*	*19*	*19*	*19*	*19*
Vista	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*
Mira Loma	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*
Substation Reactive Compensation	n/a	n/a	28	n/a	n/a	n/a	n/a	n/a
Transmission (>200kV) - Overhead (OH)	74	80	59	55	40	40	55	49
Transmission (>200kV) - Underground (UG)	n/a	n/a	100	126	241	242	138	179
Telecom	2	2	2	2	2	2	2	2
Transmission Telecom	1	1	1	1	1	1	1	1
Power System Control	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Real Properties	60	192	50	64	44	44	63	59
Environmental	13	13	8	6	6	6	6	6
Known Risks	24	26	15	59	80	78	61	68
Direct cost	$194	$354	$285	$351	$454	$454	$365	$403
Contingency	28	52	68	$51	67	67	54	59
Total Network Upgrades	$222	$406	$353	$402	$520	$521	$419	$463
Interconnection Facilities (Customer):								
Prelim. Engineering, Licensing & Permitting	$0.3	$0.7	$0.3	$0.7	$0.7	$0.7	$0.7	$0.7
Substation	7	8	7	7	7	7	7	7
Wildlife (Interconnection Facilities)	*7*	*8*	*7*	*7*	*7*	*7*	*7*	*7*
Environmental	1	1	1	0.2	0.2	0.2	0.2	0.2
One-time cost (distribution relocation)	2	2	2	0.3	0.3	0.3	0.3	0.3
Direct cost	$10	$11	$10	$8	$8	$8	$8	$8
Contingency	1	2	1	1	1	1	1	1
ITCC	3	3	3	2	2	2	2	2
Total Interconnection Facilities	$14	$16	$14	$12	$12	$12	$12	$12
TOTAL RTRP (Network Upgrade & Interconnection Facilities)	$236	$421	$367	$414	$532	$532	$431	$474

B. Estimated Direct Costs

Q. What is included in SCE's estimates of the direct costs for the Proposed Project and each FSEIR alternative?

A. Estimated direct costs are based on applying unit costs to the scopes of work developed for the Proposed Project and each FSEIR project alternative for different project components including siting, environmental surveys, licensing, preliminary and final engineering, construction, labor, materials, real estate, telecommunications, known risks, environmental monitoring and mitigation. The scope of work used for these estimates is based on the preliminary project engineering and project description information described in the 2013 Final Environmental Impact Report ("FEIR") and FSEIR developed pursuant to the California Environmental Quality Act ("CEQA").

Q. What is included in SCE's estimates of the labor costs for the Proposed Project and each FSEIR alternative?

A. Labor includes "field personnel" and "field indirects." Field personnel are based on assumptions for the make up of various crews required to safely and effectively construct the Project's components. Field indirects represent resources required to support the construction activities, such as project management and environmental/quality control.

Q. What is included in SCE's estimates of the material and equipment costs for the Proposed Project and each FSEIR alternative?

A. Material and equipment costs include estimates for steel, concrete, transformers, circuit breakers, relays, insulators, transmission and distribution conductors, grounding fiber optic wires, and any other material and equipment required to perform project work.

Q. What is included in SCE's estimates of the real properties costs for the Proposed Project and each FSEIR alternative?

A. Estimated real properties costs include the fee acquisition of the Wildlife Substation property, as well as all costs related to the right-of-way acquisition associated with approximately 10 miles of double circuit 230 kV transmission line, including telecom facilities and construction activities.

Q. What is the basis for SCE's estimated costs for the Proposed Project and each FSEIR alternative?

A. SCE's process for estimating the total capital required for the construction of the Proposed Project employs a "bottom up" approach. This means that SCE starts with the scope of work for the Proposed Project and alternatives and applies anticipated unit costs based on various previously completed projects and/or project vendor bids. SCE also takes into consideration the expected construction means and methods.

To the sum of the total estimated material, construction labor, supporting labor, *etc*. costs, a contingency is applied to account for the inherent uncertainties of the Project due to its stage in the project life cycle. Project contingency amounts were applied in a manner consistent with Association for the Advancement of Cost Engineering ("AACE") guidelines.[32]

SCE's estimates are based on the AACE's engineering definition commensurate with Class 4 estimate.[33] Further, SCE's cost estimates are developed in a manner consistent with California Public Utilities Code (PUC) § 1005.5(a), which provides:

> (a) Whenever the commission issues to an electrical or gas corporation a certificate authorizing the new construction of any addition to or extension of the corporation's plant estimated to cost greater than fifty million dollars ($50,000,000), the commission shall specify in the certificate a maximum cost determined to be reasonable and prudent for the facility. *The commission shall determine the maximum cost using an estimate of the anticipated construction cost, taking into consideration the design of the project, the expected duration of construction, an estimate of the*

32. AACE was formerly known as the American Association of Cost Engineers.

33 *See* Attachment N (AACE International Recommended Practice No. 96R-18 defining various estimating "classes," their corresponding maturity levels, and end usage).

> *effects of economic inflation, and any known engineering difficulties associated with the project* (emphasis added).

Q. How are the estimated costs of the Proposed Project and FSEIR alternatives presented in Table 2 and the cost estimate workpapers included here as <u>Attachment O</u>?

A. Estimates of the expected direct costs of the primary components of the Proposed Project and each FSEIR alternative are listed in Table 2 and the cost estimate workpapers included here as <u>Attachment O</u>. The cost workpapers also show the total amount of estimated direct costs and contingency. As presented, the estimated costs are organized by type, including substation work, 230 kV transmission lines (both overhead and underground), telecommunications, real properties, environmental costs, *etc.*

C. <u>SCE's Contingency Estimate</u>

Q. What is the item "Contingency" in the estimate, as that term is used in this testimony?

A. "Contingency" is defined by the AACE as "specific provision for unforeseeable elements of cost within the defined project scope." Contingency amounts are consistent with AACE International recommended practice No. 96R-18, *Public Review Draft – Cost Estimate Classification System – As Applied in Power Transmission Line Infrastructure Projects*. AACE 96R-18 is attached hereto as <u>Attachment N</u>.

Q. What is the purpose of adding a contingency estimate?

A. The purpose of contingency is to address significant uncertainties associated with the level of scope definition of a project.

Q. Did SCE include a contingency estimate for the direct costs of the Proposed Project and each FSEIR alternative?

A. Yes.

Q. Why did SCE include a contingency estimate for the direct costs of the Proposed Project and each FSEIR alternative?

A. The scope definition of RTRP at this stage is preliminary. As such, it is reasonable and prudent to assume a level of contingency to mitigate the level of uncertainties given this stage of the Project's development. It is industry-standard estimating practice to include a level of contingency when forecasting project costs.

Q. What factors does this contingency assumption attempt to account for?

A. SCE's contingency attempts to account for uncertainties related to but not limited to the following:

- Unforeseeable elements of cost within the defined Project scope;
- Material quantity variances within the defined scope;
- Minor material cost uncertainties;
- Labor hour variances within the defined scope;
- Minor labor cost uncertainties;
- Minor fluctuations in currency exchange rates; and
- Outage scheduling risks.

Q. Are there any factors that the contingency assumption cannot account for?

A. Yes. Contingency estimates cannot reasonably account for the following:

- Major project scope changes, for example if the Commission directs SCE to:
  - build a different transmission line route that is materially different from the alternatives studied in the FEIR and/or FSEIR;
  - use a different transmission line technology;
  - use different substation technologies;
  - construct the substation on a site other than the proposed site of the Wilderness and Wildlife Substations.
- Major schedule changes;
- Major price increases for material and labor;
- Regulatory approval delays;
- Discovery of subsurface conditions that are significantly different from presently available information suggests;
- Unforeseeable or unexpected environmental conditions and/or mitigation requirements;

- More restrictive condemnation requirements that prevent or significantly limit SCE's ability to acquire properties needed for new transmission line right-of-way;
- Intervenor and/or property owner legal challenges leading to project delay;
- Unavailability of skilled labor due to nationwide and worldwide demand, and/or strikes;
- Unavailability of materials and/or equipment due to nationwide and worldwide demand late delivery or faulty materials;
- Contractor nonperformance; and
- *Force majeure* events, property or casualty losses.

Q. What are the standards applicable to determining the appropriate contingency amount for the Proposed Project?

A. As noted in Table 2, the Proposed Project is based on preliminary scope of work which is comparable to AACE's "Class 4" estimate.[34]

Q. What is the contingency amount included in the cost estimate for both the Proposed Project and each FSEIR alternative?

A. SCE's updated Proposed Project cost estimate (Updated SCE Hybrid 2018 Constant (Column (D)), includes a contingency allocation of 15% on remaining direct cost and known risk estimates.

Q. How was the 15% contingency estimate developed for this project?

A. According to current level of engineering information, SCE believes the Updated SCE Hybrid 2018 Constant and estimates for other FSEIR project alternatives are at AACE Class 4 equivalent level. SCE based its 15% contingency estimate on AACE's standards, as well as the professional judgment and experience of SCE's engineering and construction professionals.

SCE applied unit costs to scopes developed by SCE's engineering department to develop the direct cost estimates. Additionally, SCE applied the professional judgment and experience of SCE's engineering and construction professionals to derive expected dollar values of known

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[34] *See* AACE International Recommended Practice No. 96R-18.

risks that may occur over the life cycle of the project. SCE applied a 15% contingency factor, which has also been the Commission's stated preference in previous proceedings, to cover uncertainties beyond known risks. SCE believes that given the utilization of the most updated unit costs and expected values of known risks, a 15% contingency provides adequate accuracy to determine the maximum reasonable costs for the Proposed Project and FSEIR alternatives.

D. Changes to the Project Scope and Estimated Costs Since SCE's Amended CPCN Application

Q: Has SCE made any changes to the Proposed Project since the time of the amended CPCN application (April 2015) that affected the scope of the Proposed Project?

A: Yes, SCE has made changes to the Proposed Project since the time of the amended CPCN application (submitted on or about April 30, 2015). Most notably, on or about August 17, 2016, SCE filed its Supplemental Response to Question 3 of the May 22, 2015 Deficiency Report for RTRP (attached as Attachment P to this testimony) wherein, pursuant to discussions and subsequent agreements between SCE, Riverside ("Riverside") and the owners of the Riverbend and Vernola Apartment Projects, SCE proposed to pursue, as its preferred Project route, a "hybrid" aboveground / underground alternative 230 kV transmission line route (the "Hybrid Route") in the pending RTRP CPCN proceeding. In contrast to the originally proposed RTRP project configuration, the Hybrid Route proposes underground construction of the 230 kV transmission lines within public rights-of-way immediately adjacent to the Riverbend and Vernola Apartment projects, in order to avoid directly impacting them. These changes are generally depicted in Attachment P, as well as described in the FSEIR developed in support of RTRP. Further, SCE has continued to refine engineering scope and has responded to numerous data and information requests from the CPUC that have further resulted in scope refinements and/or development of additional engineering information related to the Proposed Project.

These scope changes are reflected in the cost estimates presented in Table 2 and the cost workpapers associated with the Proposed Project attached as Attachment O hereto.

Q: Do the changes in scope require any updates to the summary of the Proposed Project as explained in the amended CPCN application?

A. Yes. The project components in the project description have changed as a result of the modifications to the Proposed Project from approximately ten (10) miles of 230 kV overhead route to a "hybrid" aboveground / underground route that consists of eight (8) miles of 230 kV overhead and two (2) miles of 230 kV underground and are accurately reflected in the FSEIR. Other major scope elements remain the same.

As reflected in the FSEIR, the Proposed Project's major scope elements include:

Substation

- Construct new 230 kV Substation (Wildlife) to interconnect to Riverside's proposed 230 kV / 69 kV Substation (Wilderness);
- Construct one Mechanical Electrical Equipment Room (MEER) at Wildlife Substation;
- Construct 230 kV switchrack at Wildlife Substation;
- Loop-in existing Mira Loma – Vista #1 230 kV Transmission line into Wildlife Substation;
- Upgrade relay protection at Mira Loma and Vista substations.

Transmission Lines (>200kV)

- Construct approximately eight miles of new double circuit 230 kV overhead transmission line;
- Construct approximately two miles of new double circuit 230 kV underground transmission line;
- Modify an existing tower of the Mira Loma-Vista #1 230 kV line to connect the new double circuit line and create a loop from the existing Mira Loma-Vista #1 230 kV Transmission Line into the proposed Wildlife Substation.

Telecommunications

- Install new fiber optic between Pedley and Wildlife Substations;
- Install necessary facilities to utilize Riverside's fiber optic network between Vista and Wildlife Substations;
- Install Optical Ground Wire ("OPGW") on the new 230 kV transmission line.

Transmission (<200kV) & Distribution

- Relocate existing distribution lines at eight locations where crossing new, proposed 230 kV lines.

Q: ***Do the costs of the Hybrid Route differ from the cost estimates for the original RTRP proposal as presented in the amended CPCN application (April 2015)?***

A: Yes, to fully consider the costs of the Hybrid Route, as well as certain other engineering refinements, SCE recently updated the estimated costs for RTRP. For reference, Table 2 includes the estimated costs of:

- 2015 CPCN Application – Column (A) presents the costs presented in the 2015 CPCN Application for the originally proposed, all overhead route. Column (A) includes approximately ten (10) miles of overhead transmission line route.
- CPCN Application 2018 Constant – Column (B) presents the original CPCN Application route but updated to reflect 2018 Constant dollars and present-day baseline conditions, including adjustments for licensing, real properties costs, and escalation.
- SCE Hybrid 2015 Constant – Column (C) presents the Hybrid Route as calculated in 2015 Constant dollars. Column (C) reflects SCE's Proposed Project of eight (8) miles of overhead transmission line route and two (2) miles of underground transmission line route.
- Updated SCE Hybrid 2018 Constant – Column (D) presents the Hybrid Route in 2018 Constant dollars and present-day baseline conditions, including adjustments accounting for engineering refinements and escalation.

As described in Table 2 Column (D), the cost estimate for SCE's Network Upgrades is $402 million, plus another $12 million for Riverside's Interconnection Facilities, for a total estimated Hybrid Route cost of $414 million in 2018 constant dollars. In summary, the cost estimate for the version of RTRP originally proposed by SCE has unavoidably increased since 2015, generally driven by changes to anticipated costs of Licensing, Transmission Underground (>200 kV), Real Properties, and Known Risks categories.

1. Differences between the cost estimates presented in Table 2

Q: ***Please describe the factors contributing to the cost differences between SCE's originally proposed, all overhead project (Column (A)) and SCE's proposed Hybrid Route (Column (C)).***

A: As referenced previously, Attachment P and the FSEIR generally depicts the changes made to accommodate the undergrounding of approximately two (2) miles of RTRP's proposed route. While based on preliminary engineering and subject to change, scope changes associated with the proposed Hybrid Route include:

- increased costs for the need for reactive compensation as a result of partial undergrounding;
- increased costs for approximately two (2) miles of 230 kV undergrounding;
- decreased costs for approximately two (2) miles of 230 kV overhead transmission;
- decreased costs for land acquisitions due to re-routing of transmission line from private lands to public streets in Franchise granted by the City of Jurupa Valley;[35]
- decreased costs for environmental compliance associated with the proposed underground section of the line (e.g., reduced monitoring requirements in previously disturbed city-streets when compared with open space, etc.);
- increased cost for combined "Known Risks" and contingency to account for the revision from all overhead to partial underground.

Q: Please describe the factors contributing to the estimated increase in costs noted between the SCE Hybrid 2015 Constant (Column (C)) and the SCE Hybrid 2018 Constant (Column (D)).

A: Since 2015, SCE has continued to refine and advance its engineering of RTRP. As the maturity level of project definition and engineering deliverables increased, consistent with AACE recommended practice no. 96R-18 (attached hereto as Attachment N), RTRP's Cost Estimate classification has been upgraded from AACE equivalent Class 5 to Class 4.

The revised direct capital estimates for SCE Hybrid 2018 Constant dollars (Column (D)) for the Licensing, Substation, Transmission Overhead (> 200 kV), Transmission Underground (> 200 kV),

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[35] As referenced below, the City of Jurupa Valley has granted SCE a Franchise in accordance with the Franchise Act of 1937 (Ca. Pub. Utilities Code Section 6201, et seq.). As described in that agreement, "'Franchise' shall mean and include any authorization granted hereunder to use, and to construct and use, electric transmission and distribution facilities, including communication circuits, for transmitting and distributing electricity for all purposes, under, along, across, and upon the public streets, ways, alleys, and places within the City."

Telecommunications, and Environmental categories are also derived based on updated project scope information, as compared with SCE's 2015 Constant Dollar estimate (Column (C)).

The drivers for the cost adjustments include:

- increased costs for Licensing to account for the increased duration and efforts associated with the regulatory approval process, as well as the associated reimbursal to Riverside of such Licensing costs;
- increased costs for the Underground Transmission estimate due to a refined Project scope and updated unit price;
- increased costs for Real Properties estimates to account for 2018 values of the associated real property acquisitions;
- decreased costs for reactive compensation given updated engineering study indicating such components were not necessary;
- increased costs associated with expected known risk dollars due to the potential increase in underground cable prices and/or underground construction costs due to unknown geologic features and/or the presence of conflicting utilities; and
- the escalation of the total project cost from 2015 Constant Dollars to 2018 Constant Dollars.[36]

Additionally, the SCE Hybrid 2015 Constant (Column (C)) reflected a 35% contingency applied to the undergrounding elements ("Transmission (>200 kV) – Underground"), and a 15% contingency applied on the remaining project elements. The applied 35% contingency for the underground elements was originally included to account for events and issues that are difficult to predict given SCE's relative lack of experience undergrounding bulk transmission lines above 200 kV and unknown subsurface conditions. However, based on SCE's experience with, and the data collected from, a recently completed project that included bulk transmission undergrounding - *i.e.,* the Tehachapi Renewable Transmission Project ("TRTP") - as well as further refinements to project engineering and an improved

[36] The "escalation" factors used to determine the annual change in the price levels of the goods and services that is expected to occur is depicted in the inflationary index, attached as Attachment M hereto.

understanding of field conditions, SCE now supports applying a 15% contingency for all project elements (including the undergrounding scope) as reflected in the Updated SCE Hybrid 2018 Constant figure (Column (D)).

Q. Please describe why SCE updated the costs associated with its originally proposed, all overhead route, presented as CPCN Application 2018 Constant (Column (B)) in Table 2?

A: As presented in CPCN Application 2018 Constant (Column (B)) of Table 2 above, SCE updated the estimated costs associated with its originally proposed, all overhead route in 2015 (presented for comparison in Column (A)). Various circumstances changed between 2015 and 2018 that were not accounted for in the originally presented 2015 estimate. SCE developed the information described in CPCN Application 2018 Constant (Column (B)) of Table 2 in order to provide a consistent basis of comparison (*i.e.*, 2018 Constant Dollars) across all alternative route designs before the Commission.

For example, the estimated costs presented in 2015 do not take into account changes to the land uses along the proposed project route (most notably Jurupa Valley's approval of the Riverbend and Vernola Apartment housing developments) that have occurred since the CPCN Application was submitted. Those changes increased estimated Real Properties costs to account for current (2018) land values that would be associated with the acquisition of developed parcels. Additional increases were also noted for Licensing, accounting for increased regulatory duration, and to reimburse Riverside for licensing spend, as well as the escalation of total project cost from 2015 to 2018 constant dollars.

E. Public Utilities Code Section 1005 And Adjustment Of The Maximum Reasonable And Prudent Cost Estimate

Q. Pub. Util. Code Section 1005.5(a) establishes that the Commission shall specify a maximum prudent and reasonable cost for the proposed facilities and section 1005.5(b) allows the utility applicant to seek to increase the maximum cost that the Commission believes is reasonable

and prudent, after the decision granting the CPCN has been issued.[37] Will future adjustments be necessary for RTRP?

A. It is not known at this time, but it is a possibility. At this stage in the project development process, the RTRP's design is preliminary, meaning it has been refined but is not supported by final engineering. SCE may need to request adjustments to the established maximum prudent and reasonable cost ("MPRC") based on changes in cost estimates upon completion of final engineering. Such adjustments may be necessary to reflect adjustments in project costs:

- resulting from the approval of an RTRP alternative not proposed in the RTRP proceeding;
- because of any unanticipated delays in starting the project or inflation;
- as a result of final design criteria;
- resulting from the ultimately adopted mitigation measures (and mitigation monitoring program); and
- related to equipment and raw materials, for example, the price of steel, concrete, other raw materials, and equipment that, in fact, increase the cost of the Project.

Q: Do you believe that the information provided in SCE's Direct Testimony sufficient for the purposes of establishing the MPRC for the RTRP?

A: Yes.

Q: Please explain why you believe that the information provided in SCE's Direct Testimony is sufficient for the purposes of establishing the MPRC for the construction of RTRP.

[37] *See* Pub. Util. Code §§ 1005.5(a) ("Whenever the commission issues to an electrical . . .corporation a certificate authorizing the new construction of any addition to or extension of the corporation's plant estimated to cost greater than fifty million dollars ($50,000,000), the commission shall specify in the certificate a maximum cost determined to be reasonable and prudent for the facility"), 1005.5(b) ("After the certificate has been issued, the corporation may apply to the commission for an increase in the maximum cost specified in the certificate. The commission may authorize an increase in the specified maximum cost if it finds and determines that the cost has in fact increased and that the present or future public convenience and necessity require construction of the project at the increased cost; otherwise, it shall deny the application.")

A: SCE's estimate for the RTRP Hybrid Route is based on the most recent site surveys, environmental information and engineering analysis and includes reasonable estimates for total project costs based on SCE's recent project experience. In addition, SCE has carefully itemized costs associated with RTRP and its alternatives. A copy of SCE's RTRP cost workpapers containing breakout information and detailed cost estimates (*e.g.,* cost regarding engineering, materials procurement, construction labor unit rates, overhead rates, *etc*.) regarding the forecasted gross direct expenditures estimated to be necessary to construct various elements of the RTRP Hybrid Route is attached as Attachment O to this testimony. A copy of workpapers regarding the same information for all alternatives studied in detail in the FSEIR, including the designated environmentally superior alternative, are attached as Attachment O to this testimony.

F. Estimated Costs of the Project Alternatives Considered in the FSEIR

Q: What are the total estimated costs for each FSEIR alternative presented in this testimony?

A: As shown in Table 2 and the Estimated Cost Workpapers attached as Attachment O hereto, the total costs, inclusive of both Network Upgrades and Interconnection Facilities, presented in 2018 constant dollars for each FSEIR alternative are:

- FSEIR Alternative 1 (the FEIR's designated environmentally superior project alternative): $532 million;
- FSEIR Alternative 2: $532M
- FSEIR Alternative 3: $431 million; and
- FSEIR Alternative 4: $474 million.[38]

G. Franchise Agreement With The City of Jurupa Valley

Q: Does SCE have a franchise agreement with the City of Jurupa Valley?

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[38] It is my understanding that SCE intends to make the legal argument that the estimated cost of the alternatives considered in the FSEIR, including Alternative 1 (which was designated as the environmentally superior project alternative), as well as the potential risk of relocation contemplated by the applicable franchise agreement between SCE and the City of Jurupa Valley (*see* below), are primary factors as to why these alternatives are infeasible as a matter of public policy.

A: Yes, the City of Jurupa Valley has granted SCE a Franchise in accordance with the Franchise Act of 1937 (Cal. Pub. Utilities Code §§ 6201, *et seq*.). As defined in the Franchise Agreement between SCE and the City of Jurupa Valley (attached as Attachment Q hereto),

> [t]he word 'Franchise' shall mean and include any authorization… to construct and use, electric transmission and distribution facilities … for transmitting and distributing electricity … under, along, across, and upon the public streets, ways, alleys, and places within the City [of Jurupa Valley].

Section 4(a) of the Franchise Agreement provides that SCE

> shall pay to the City [of Jurupa Valley] … two percent (2%) of the [SCE's] gross annual receipts arising from the use, operation, or possession of this Franchise… [but not] less than one percent (1%) of [SCE's] gross annual receipts derived from the sale of electricity within the City [of Jurupa Valley].

Section 4(g) of the Franchise Agreement governs the potential relocation of facilities installed within franchise, providing:

> Removal or Relocation of Facilities. As required by California Public Utilities Code Section 6297, [SCE] shall remove or relocate any facilities installed, used, and maintained under the franchise if and when made necessary by any lawful change of grade, alignment or width of any public street, way, alley or place. Such removal or relocation shall be performed by [SCE] without expense to the City [of Jurupa Valley]. In no event shall [SCE] be obligated to incur the cost of removal or relocation of any Facilities which were previously removed or relocated at the request of the City [of Jurupa Valley], if the City request for the removal or relocation is delivered on a date that is less than five (5) years from the date of the

completion of a prior removal or relocation requested by the City with respect to such Facilities.

Q: ***Is a portion of the Proposed Project proposed to be located within public streets governed by the Franchise Agreement with the City of Jurupa Valley?***

A: Yes, SCE's Proposed Project alignment (the Hybrid Route) would locate approximately two (2) miles of transmission line underground within public streets in the City of Jurupa Valley. Similarly, each FSEIR Alternative also proposes various sections of RTRP's 230 kV transmission line to be constructed underground within public streets in the City of Jurupa Valley subject to the terms of the Franchise Agreement, as follows:

- FSEIR Alternative 1: approximately 4.03 miles of underground transmission line construction;
- FSEIR Alternative 2: approximately 4.06 miles of underground transmission line construction;
- FSEIR Alternative 3: approximately 2.29 miles of underground transmission line construction; and
- FSEIR Alternative 4: approximately 2.88 miles of underground transmission line construction.

Q: ***Are the annual costs associated with the Franchise Agreement captured within SCE's cost estimates provided herein?***

A: No. SCE's cost estimates provided herein address construction costs and not potential costs associated with operations and maintenance, which would include any fees paid to the City of Jurupa Valley under the Franchise Agreement.

Q: ***Has the City of Jurupa Valley offered to contribute to the additional estimated cost of undergrounding any portion of RTRP?***

A: No, upon information and belief, the City of Jurupa Valley has made no offers of any monetary compensation, any forbearance of compensation it may be due pursuant to the Franchise Agreement, and/or any offers of real property rights, including but not limited to property rights superior to those that are granted to SCE pursuant to the Franchise Agreement, in exchange for the undergrounding of any part of RTRP within its public streets.

Q: ***Was this material prepared by you or under your supervision?***

A: Yes.

Q: ***Insofar as this material is factual in nature, do you believe it to be correct?***

A: Yes.

Q: ***Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?***

A: Yes.

Q: ***Does this conclude your qualifications and prepared testimony at this time?***

A: Yes.

V.

SCE's Direct Testimony Regarding RTRP's Compliance With The Commission's Policies Governing The Mitigation Of EMF Effects Using Low-cost And No-cost Measures And The Qualifications Of Phil Hung [39]

Q: ***Please state your name and business address for the record.***

A: My name is Phil Hung, and my business address is 6042 N. Irwindale Ave, Irwindale CA 91702.

Q: ***Briefly describe your education, work history and present responsibilities at SCE.***

A: I received my Bachelor of Science in electrical engineering from Cal Poly Pomona in 1992 and my Master of Business Administration from University of Southern California's Marshall School of Business in 2013. I started my career at SCE as a professional trainee in 1990 in its Information Services Department. Over the last 25 years, I have held various positions in different groups at SCE, including Research & Development, Grid Operations, Information Technologies and in the EMF & Energy Group. I was the Senior Engineer in the EMF & Energy Group in 2008, served as the Acting Manager for the group from 2011- 2013, and subsequently became the Supervising Engineer for the EMF & Energy Group.

I am currently the Senior Advisor of SCE's Safety Programs and Compliance Group, in the Edison Safety Department. Part of my responsibilities in that role include overseeing SCE's activities related to Electric and Magnetic Fields ("EMF"), including preparing studies on EMF reduction techniques for new electrical facilities, responding to customer and employee EMF inquiries and supporting EMF research projects. I also oversee the preparation of Field Management Plans ("FMPs") for SCE's transmission and substation projects.

Q: ***Please describe your role with respect to the RTRP.***

A: I supervised the preparation of the FMPs for RTRP.

Q: ***What is the purpose of your testimony in this proceeding?***

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[39] This Section addresses Scoping Memo Issue # 9 ("*Does the project design comply with the Commission's policies governing the mitigation of EMF effects using low-cost and no-cost measures?*")

A: The purpose of my testimony in this proceeding is to sponsor portions of *Southern California Edison Company's (U 338-E) Direct Testimony Supporting Its Application For a Certificate of Public Convenience and Necessity for the Riverside Transmission Reliability Project* (the "Original CPCN Application") related to RTRP's compliance with the Commission's policies governing the mitigation of EMF effects using low-cost and no-cost measures.

Q: ***Are you familiar with the California Public Utilities Commission's ("CPUC's") policies governing electric and magnetic fields associated with electrical facilities?***

A: Yes, I am.

Q: ***Could you please describe those policies as you understand them?***

A: The CPUC has developed an integrated action plan for California in response to concerns about the potential health impacts of power frequency EMF from electric utility facilities. This plan was established by the CPUC in Decision D.93-11-013, which adopted a policy requiring investor-owned electric utilities operating within the state to incorporate various "no-cost" and "low-cost" measures into the construction of new or updated power lines and substations, and requiring each utility to develop and publish guidelines to implement this policy. The CPUC acknowledged that scientific research had not demonstrated that exposure to EMF causes health hazards and that it was inappropriate to set numeric standards that would limit exposure.

Furthermore, in 2006, the CPUC updated its EMF policy in D.06-01-042, reaffirming that health hazards from exposure to EMF had not been established and that State and federal public health regulatory agencies have determined that setting numeric exposure limits is not appropriate. The CPUC also affirmed that the existing "no-cost and low-cost" precaution-based EMF policy be continued. It is noteworthy that the CPUC's EMF policy is consistent with the latest World Health Organization ("WHO") policies and recommendations regarding EMF. In its 2007 Environmental Health Criteria on extremely low-frequency EMF, the WHO concluded that EMF health hazards have not been established and made the following recommendation:

> Provided that the health, social and economic benefits of electric power are not compromised, implementing very low-cost precautionary procedures to reduce exposures is reasonable and warranted.

Q: Can you explain how SCE considered those policies in the course of designing and planning the Project?

A: To comply with the CPUC's EMF policies, SCE evaluated the magnetic field reduction measures already incorporated in the initial engineering designs and possible additional "no-cost and low-cost" magnetic field reduction measures for the proposed line routes and substation.

Q: Can you please identify where SCE's considerations in this regard been documented?

A: SCE first prepared a FMP which was submitted to the CPUC as part of SCE's Original CPCN Application in 2015. As described in the FMP, SCE considered a number of "no-cost and low-cost" magnetic field reduction design options for incorporation into the Project. The options recommended for incorporation in the FMP were based upon preliminary engineering designs performed by SCE as of the date of the FMP. However, SCE later filed an *Amended Application Of Southern California Edison Company (U 338-E) For A Certificate Of Public Convenience And Necessity To Construct The Riverside Transmission Reliability Project* (the "Amended CPCN Application"), proposing to construct the project with a hybrid design consisting partially of overhead transmission line components and partially of underground transmission line components (the "Hybrid Design"). CPUC staff then prepared a Final Subsequent Environmental Impact Report ("FSEIR") that analyzed the Hybrid Design as well as a number of alternatives. The FSEIR identifies four alternatives (which it denotes Alternative 1, Alternative 2, Alternative 3 and Alternative 4, respectively), as well as at least one combination thereof (*i.e.*, a mix of Alternative 1 and Alternative 4), as environmentally superior to SCE's proposed Hybrid Design. Therefore, to ensure that the CPUC has sufficient information regarding SCE's approach to reducing electric and magnetic fields if RTRP were to be constructed, SCE has prepared FMPs for the Hybrid Design and each of the four alternatives deemed by the FSEIR to be environmentally superior to the Hybrid Design. The Hybrid Design FMP analysis matches the EMF analysis presented in the FSEIR. The FMPs for the Hybrid Design, Alternative 1, Alternative 2, Alternative 3 and Alternative 4, respectively, are attached hereto as part of Attachment R. Each of those FMPs describes "no-cost" and "low-cost" magnetic field reduction design options that could be implemented into the applicable design, as appropriate.

SCE plans to incorporate the options identified in the applicable FMP for any version of RTRP that might ultimately be approved by the CPUC (including the Hybrid Design or any alternative, as the case may be), assuming that the engineering for the applicable approved design does not substantially change.[40] If the final engineering designs are significantly different than preliminary engineering designs, however, SCE would implement comparable "no-cost and low-cost" magnetic field reduction design options.

Q: Do you believe that the options recommended in the FMPs for magnetic field reduction design represent modifications that would render RTRP consistent with the CPUC's policies regarding EMF?

A: Yes. I believe that the options recommended in the above-mentioned FMPs, if implemented into whichever applicable alternative might ultimately be constructed, would render RTRP consistent with the CPUC's policies – described in CPUC decisions numbered D.93-11-013 and D.06-01-042 – regarding EMF, and also with recommendations made by the WHO. Furthermore, each of the options meets the "EMF Design Guidelines" prepared by SCE and filed with the CPUC, as well as all applicable national and State safety standards for new electric facilities.

Q: Was this material prepared by you or under your supervision?

A: Yes.

Q: Insofar as this material is factual in nature, do you believe it to be correct?

A: Yes.

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40 The EMF reduction options for the Hybrid Design and for Alternatives 1 through 4 are considered in the applicable FMPs based on SCE's preliminary engineering only, particularly given that Alternatives 1 through 4 were not developed by SCE and SCE only became aware of them through reviewing the FEIR.

Q: ***Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?***

A: Yes.

Q: ***Does this conclude your qualifications and prepared testimony at this time?***

A: Yes.